

October 2004

Hydro Plant Risk Assessment Guide

Chapter xx: Transformer Condition Assessment

xx.1 GENERAL

Power transformers are key components in the power train at hydroelectric powerplants and are appropriate for analysis under a risk assessment program. Transformer failure can have a significant economic impact due to long lead times in procurement, manufacturing, and installation in addition to high equipment cost. According to the Electric Power Research Institute (EPRI): “Extending the useful life of power transformers is the single most important strategy for increasing life of power transmission and distribution infrastructures, starting with generator step-up transformers (GSU) at the powerplant itself” (EPRI Report # 1001938).

Determining the existing condition of power transformers is an essential step in analyzing the risk of failure. This chapter provides a process for arriving at a Transformer Condition Index. This condition index may be used as an input to the risk-and-economic analysis computer model where it adjusts transformer life expectancy curves. The output of the economic analysis is a set of alternative scenarios, including costs and benefits, intended for management decisions on replacement or rehabilitation.

xx.2 SCOPE / APPLICATION

The transformer condition assessment methodology outlined in this chapter applies to oil-filled, power transformers (> 500 kVA) currently in operation.

This guide is not intended to define transformer maintenance practices or describe in detail transformer condition assessment inspections, tests, or measurements. Utility maintenance policies and procedures must be consulted for such information.

xx.3 CONDITION AND DATA QUALITY INDICATORS AND TRANSFORMER CONDITION INDEX

The following four condition indicators are generally regarded by hydro powerplant engineers as providing a sound basis for assessing transformer condition:

- Insulating Oil Analysis (DGA and Furan)
- Power Factor and Excitation Current Tests
- Operation and Maintenance History
- Age

These indicators are based on Tier 1 inspections, tests, and measurements conducted by utility staff or contractors over the course of time. The indicators are expressed in numerical terms and are used to arrive at an overall Transformer Condition Index.

An additional stand-alone indicator is used to reflect the quality of the information available for scoring the Transformer Condition Index. In some cases, data may be missing, out-of-date, or of questionable integrity. Any of these situations could affect the accuracy of the associated condition indicator scores as well as the validity of the condition index. Given the potential impact of poor or missing data, a Data Quality Indicator is rated during the Tier 1 assessment as a means of evaluating and recording confidence in the final Transformer Condition Index.

Additional information regarding transformer condition may be necessary to improve the accuracy and reliability of the Transformer Condition Index. Therefore, in addition to the Tier 1 condition indicators, this Guide describes a “toolbox” of Tier 2 inspections, tests, and measurements that may be applied to the Transformer Condition Index, depending on the specific issue or problem being addressed. Tier 2 tests are considered non-routine. However, if Tier 2 data is readily available, it may be used to supplement the Tier 1 assessment. Alternatively, Tier 2 tests may be deliberately performed to address Tier 1 findings. Results of the Tier 2 analysis may either increase or decrease the score of the Transformer Condition Index. The Data Quality Indicator score may also be revised during the Tier 2 assessment to reflect the availability of additional information or test data.

The Transformer Condition Index may indicate the need for immediate corrective actions and/or follow-up Tier 2 testing. The Transformer Condition Index is also suitable for use as an input to the risk-and-economic analysis model.

Note: A severely negative result of ANY inspection, test, or measurement may be adequate in itself to require immediate de-energization, or prevent re-energization, of the transformer regardless of the Transformer Condition Index score.

xx.4 INSPECTIONS, TESTS, AND MEASUREMENTS

The hierarchy of inspections, tests, and measurements is illustrated in Figure 1 (Transformer Condition Assessment Methodology). Table 16 briefly describes the activities related to conducting the transformer condition assessment.

Inspections, tests, and measurements (“tests”) performed to determine transformer condition are divided into two tiers or levels. Tier 1 tests are those that are routinely accomplished as part of normal operation and maintenance or are readily discernible by examination of existing data. Results of Tier 1 tests are quantified below as condition indicator scores that are weighted and summed to arrive at a Transformer Condition Index. Tier 1 tests may indicate abnormal conditions that can be resolved with standard corrective maintenance solutions. To the extent that Tier 1 tests result in immediate corrective maintenance actions being taken by plant staff, then adjustments to the condition indicators below should be reflected and the new results used when computing the overall Tier 1 Condition Index. Tier 1 test results may also indicate the need for additional investigation, categorized as Tier 2 tests.

Tier 2 tests are considered non-routine. Tier 2 test results may affect the Transformer Condition Index established using Tier 1 tests but also may confirm or disprove the need for more extensive maintenance, rehabilitation, or transformer replacement.

Inspection, testing, and measurement methods are specified in technical references specific to the electric utility.

This guide assumes that Tier 1 and Tier 2 inspections, tests, and measurements are conducted and analyzed by staff suitably trained and experienced in transformer diagnostics. In the case of more basic tests, this may be qualified staff who are competent in these routine procedures. More complex inspections and measurements may require a transformer diagnostics “expert”.

This guide also assumes that inspections, tests, and measurements are conducted on a frequency that provides accurate and current information needed by the assessment. In some cases, it may be necessary to conduct tests prior to this assessment to acquire current data.

Results of the transformer condition assessment may cause concern that justifies more frequent monitoring. Utilities should consider the possibility of taking more frequent measurements (e.g., oil samples) or the installation of on-line monitoring systems (e.g., gas-in-oil) that will continuously track critical quantities. This will provide additional data for condition assessment and establish a certain amount of reassurance as transformer alternatives are being explored.

xx.5 SCORING

Transformer condition indicator scoring is somewhat subjective, relying on transformer condition experts. Relative terms such as “Results Normal” and “Degradation” refer to results that are compared to industry accepted levels; or to baseline or previous (acceptable) levels on this equipment; or to equipment of similar design, construction, or age operating in a similar environment.

xx.6 WEIGHTING FACTORS

Weighting factors used in the condition assessment methodology recognize that some condition indicators affect the Transformer Condition Index to a greater or lesser degree than other indicators. These weighting factors were arrived at by consensus among transformer design and maintenance personnel with extensive experience.

xx.7 MITIGATING FACTORS

Every transformer is unique and, therefore, the methodology described in this chapter cannot quantify all factors that affect individual transformer condition. It is important that the Transformer Condition Index arrived at be scrutinized by engineering experts. Mitigating factors specific to the utility may determine the final Transformer Condition Index and the final decision on transformer replacement or rehabilitation.

xx.8 DOCUMENTATION

Substantiating documentation is essential to support findings of the assessment, particularly where a Tier 1 condition indicator score is less than 3 (i.e., less than normal) or where a Tier 2 test results in subtractions from the Transformer Condition Index. Test results and reports, photographs, O&M records, or other documentation should accompany the Transformer Condition Assessment Summary Form.

xx.9 CONDITION ASSESSMENT METHODOLOGY

The condition assessment methodology consists of analyzing each condition indicator individually to arrive at a condition indicator score. The scores are then weighted and summed to determine the Transformer Condition Index. The Transformer Condition Index is applied to the Transformer Condition-Based Alternatives, Table 15, to determine the recommended course of action.

Reasonable efforts should be made to perform Tier 1 inspections, tests, and measurements. However, when data is unavailable to properly score a condition indicator, it may be assumed that the score is “Good” or numerically equal to some mid-range number such as 2. This strategy must be used judiciously to prevent erroneous results and conclusions. In recognition of the potential impact of poor or missing data, a separate Data Quality Indicator is rated as a means of evaluating and recording confidence in the final Generator Condition Index.

xx.10 TIER 1 - INSPECTIONS, TESTS, MEASUREMENTS

Tier 1 inspections, tests, and measurements are routinely accomplished as part of normal operation and maintenance, or are readily discernible by examination of existing data. Tier 1 test results are quantified below as condition indicators that are weighted and summed to arrive at a Transformer Condition Index. Tier 1 inspections, tests, and measurements may indicate abnormal conditions that can be resolved with standard corrective maintenance solutions. Tier 1 test results may also indicate the need for additional investigation, categorized as Tier 2 tests.

Transformer Condition Indicator 1 - Insulating Oil Analysis

Dissolved gas analysis is the most important factor in determining the condition of a transformer because, being performed more frequently than other tests, it may be the first indication of a problem. Insulating oil analysis can identify internal arcing, bad electrical contacts, hot spots, partial discharge, or overheating of conductors, oil, tank, or cellulose. The “health” of the oil is reflective of the health of the transformer itself. Dissolved gas analysis (DGA) consists of sending transformer insulating oil samples to a commercial laboratory for analysis. The most important indicators are the individual and total dissolved combustible gas (TDCG) generation rates, based on IEC and IEEE standards. Although gas generation rates are not the only indicator, they are reasonable for use in determining the condition indicator score.

Furanic analysis may indicate a problem with the paper insulation which could affect transformer longevity. A baseline furanic analysis should be made initially and repeated if the transformer is overheated, overloaded, aged, or after changing or processing the oil.

Physical tests such as interfacial tension (IFT), acidity, moisture content, and dielectric strength usually indicate oil conditions that can be remedied through various reclamation processes. Therefore, they are not indicative of overall transformer condition that would lead to replacement. Such tests do not affect the Insulating Oil Condition Indicator score.

Results of the insulating oil analysis are applied to Table 1 to arrive at an appropriate Condition Indicator Score.

Table 1 – Insulating Oil Analysis Scoring	
Results (See Notes 1 & 2)	Condition Indicator Score
Total Dissolved Combustible Gas (TDCG) generation rate less than 30 ppm/month and all individual combustible gas generation less than 10 ppm/month. Exceptions: CO generation less than 70 ppm/month and acetylene (C ₂ H ₂) generation rate 0 ppm. AND 2FAL Furans 150 ppb (parts per billion) or less. (See Note 3)	3
TDCG generation rate between 30 and 60 ppm/month and all individual combustible gas generation rate less than 15 ppm/month. Exceptions: CO generation rate less than 150 ppm/month and C ₂ H ₂ generation rate 0 ppm. OR 2 FAL Furans between 150 and 200 ppb. (See Note 3)	2
TDCG generation rate between 50 and 80 ppm/month and all individual combustible gas generation rates less than 25 ppm/month. Exceptions: CO generation rate less than 350 ppm/month and C ₂ H ₂ generation rate less than 5 ppm/month. OR 2 FAL Furans between 200 and 250 ppb. (See Note 3)	1
TDCG generation rate greater than 80 ppm/month and any individual combustible gas generation rate more than 50 ppm/month. Exceptions: CO generation more than 350 ppm/month and C ₂ H ₂ generation rate no more than 10 ppm/per month. OR 2 FAL Furans above 250 ppb. (See Note 3)	0

Note 1: The above DGA numbers are based on dissolved gas in oil generation rates and come from a combination of IEEE C57-104, IEC 60599 and Delta X Research's Transformer Oil Analysis TOA) software.

Note 2: *Any ongoing acetylene (C_2H_2) generation indicates an active arcing fault and the transformer may have to be removed from service to avoid possible catastrophic failure. A transformer may be safely operated with some C_2H_2 showing in the DGA. C_2H_2 sometimes comes from a one-time event such as a close-in lightning strike or through fault. However, if C_2H_2 is increasing more than 10 ppm per month, the transformer should be removed from service. Because acetylene generation is a critical indicator of transformer internal condition, each utility should establish practices in accordance with published standards and transformer experts to monitor any increases in gas generation and take corrective action. Increasing the frequency of DGA analysis and de-gasifying the transformer oil are potential alternatives to consider.*

Note 3: Furan limits in the table are for thermally upgraded paper. For non-thermally upgraded paper, i.e., rated 55 degrees C maximum, divide the lab test result Furan values by 3 before applying them to the table. Non-thermally upgraded paper emits approximately 3 times more Furans before a problem is indicated.

Transformer Condition Indicator 2 - Power Factor and Excitation Current Tests

Power factor insulation testing is important to determining the condition of the transformer because it can detect winding and bushing insulation integrity. Power factor and excitation current tests are conducted in the field on de-energized, isolated, and properly grounded transformers. Excitation current tests measure the single-phase voltage, current, and phase angle between them, typically on the high-voltage side with the terminals of the other winding left floating (with the exception of a grounded neutral). The measurements are performed at rated frequency and usually at test voltages up to 10 kV. The test detects shorted turns, poor tap changer contacts, and core problems.

Results of the power factor and excitation current tests are analyzed and applied to Table 2 to arrive at an appropriate Condition Indicator Score.

Table 2 – Power Factor and Excitation Current Test Scoring	
Test Results*	Condition Indicator Score
Power factor results normal (Good - G) AND Normal excitation current values and patterns compared to other phases and prior tests.	3
Power factor results show minor degradation. (Deteriorated - D) OR Minor deviation in excitation current values and patterns compared to other phases and prior tests. **	2
Power factor results show significant deterioration. (Investigate - I) OR Significant deviation in current values and patterns compared to other phases and prior tests. **	1

Power factor results show severe degradation. (Bad - B) OR Severe deviation in current values and patterns compared to other phases and prior tests. **	0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)
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* Double insulation rating in parentheses.

**Be sure to account for residual magnetism and tap changer position.

Transformer Condition Indicator 3 - Operation and Maintenance History

Operation and maintenance (O&M) history may indicate overall transformer condition. O&M history factors that may apply are:

- Sustained overloading.
- Unusual operating temperatures indicated by gages and continuous monitoring.
- Abnormal temperatures indicated by infrared scanning.
- Nearby lightning strikes or through-faults.
- Abnormally high corona detected.
- Abnormally high external temperatures detected.
- Problems with auxiliary systems (fans, radiators, cooling water piping, pumps, motors, controls, nitrogen replenishment system, and indicating and protection devices).
- Deteriorated control and protection wiring and devices.
- Increase in corrective maintenance or difficulty in acquiring spare parts.
- Anomalies determined by physical inspection* (e.g., incorrectly positioned valves, plugged radiators, stuck temperature indicators and level gages, noisy oil pumps or fans, oil leaks, connections to bushings). * External inspection or internal inspection not requiring untanking.
- Previous failures on this equipment.
- Failures or problems on equipment of similar design, construction, or age operating in a similar environment.

Qualified personnel should make a subjective determination of scoring that encompasses as many operation and maintenance factors as possible under this Indicator.

Results of the O&M history are analyzed and applied to Table 3 to arrive at an appropriate Condition Indicator Score.

Table 3 – Operation and Maintenance History Scoring	
History Results	Condition Indicator Score
Operation and Maintenance are normal.	3
Some abnormal operating conditions experienced and / or additional maintenance above normal occurring.	2

Significant operation outside normal and /or significant additional maintenance is required; or forced outage occurs; or outages are regularly extended due to maintenance problems; or similar units are problematic.	1
Repeated forced outages; maintenance not cost effective; or major oil leaks and / or severe mechanical problems; or similar units have failed.	0

Transformer Condition Indicator 4 - Age

Transformer age is an important factor to consider when identifying candidates for transformer replacement. Age is one indicator of remaining life and upgrade potential to current state-of-the-art materials. During the life of the transformer, the structural and insulating properties of materials which are used for structural support and electrical insulation, especially wood and paper, deteriorate. Although actual service life varies widely depending on the manufacturer's design, quality of assembly, materials used, operating history, current operating conditions, and maintenance history, the average expected life for an individual transformer in a large population of transformers is statistically about 40 years.

Apply the transformer age to Table 4 to arrive at the Condition Indicator Score.

Table 4 – Age Scoring	
Age	Condition Indicator Score
Under 30 years	3
30 - 45 years	2
Over 45 years	1

xx.11 TIER 1 - TRANSFORMER CONDITION INDEX CALCULATIONS

Enter the condition indicator scores from the tables above into the Transformer Condition Assessment Summary form at the end of this document. Multiply each condition indicator score by the Weighting Factor, and sum the Total Scores to arrive at the Tier 1 Transformer Condition Index.

xx.12 TIER 1 – TRANSFORMER DATA QUALITY INDICATOR

The Transformer Data Quality Indicator reflects the quality of the inspection, test and measurement results used to evaluate the transformer condition under Tier 1. The more current and complete the inspections, tests, and measurements, the higher the rating for this indicator. The normal testing frequency is defined as the organization's recommended frequency for performing the specific test or inspection.

Qualified personnel should make a subjective determination of scoring that encompasses as many factors as possible under this indicator. Results are analyzed and applied to Table 5 to arrive at a Transformer Data Quality Indicator Score.

Table 5 – Transformer Data Quality Scoring	
Results	Data Quality Indicator Score
All Tier 1 inspections, tests and measurements were completed within the normal testing frequency AND results are reliable.	10
One or more of the Tier 1 inspections, tests and measurements were completed between 6 and 24 months past the normal testing frequency.	7
One or more of the Tier 1 inspections, tests and measurements were completed between 24 and 36 months past the normal testing frequency, or some of the results are not available.	4
One or more of the Tier 1 inspections, tests and measurements were completed more than 36 months past the normal frequency, or no results are available.	0

xx.12 TIER 2 - INSPECTIONS, TESTS, MEASUREMENTS

Tier 2 inspections, tests, and measurements generally require specialized equipment or training, may be intrusive, or may require an extended outage to perform. A Tier 2 assessment is not considered routine. Tier 2 inspections are intended to affect the Transformer Condition Index number established using Tier 1 but also may confirm or refute the need for more extensive maintenance, rehabilitation, or transformer replacement.

Note that there are many tests that can give information about the various aspects of transformer condition. The choice of tests should be made based on known information gathered by inspection history, other test results, company standards, and Tier 1 assessment. Many Tier 2 tests are used to detect or confirm a similar defect in the condition of the transformer. In the event that several Tier 2 tests are performed that assess the same condition issue, then the test with the largest adjustment should be used in recalculating the Condition Index. Since Tier 2 tests are being performed by, and/or coordinated with, knowledgeable technical staff, the decision on which test is most significant and how these tests overlap in application is left to the experts. The important factor is to avoid adjusting the Condition Index downward twice or more simply because two or more tests are completed for the same suspected condition.

For Tier 2 evaluations, apply only the applicable adjustment factors per the instructions above and recalculate the Transformer Condition Index using the Transformer Condition Assessment Survey Form at the end of this document. An adjustment to the Data Quality Indicator score may be appropriate if additional information or test results were obtained during the Tier 2 assessment.

Test T2.1 Turns Ratio Test

The transformer turns ratio (TTR) test detects shorts between turns of the same coil, which indicates insulation failure between the turns. These tests are performed with the transformer de-energized and may show the necessity for an internal inspection or removal from service. Results are analyzed and applied to Table 6 to arrive at a Transformer Condition Index adjustment.

Table 6 – Turns Ratio Test Scoring	
Test Results	Adjustment to Transformer Condition Index
Less than 0.20 percent difference from nameplate V_1/V_2 and compared to previous readings.	No Change
0.20 to 0.50 percent difference compared to nameplate V_1/V_2 .	Subtract 1.0
Greater than 0.5 percent difference compared to nameplate V_1/V_2 .	Subtract 5.0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)

Test T2.2 Short Circuit Impedance Test

Sometimes called Percent Impedance or Leakage Reactance, these tests are conducted in the field and compared to nameplate information, previous tests, and similar units to detect deformation of the core or windings caused by shipping damage, through faults, or ground faults. Some difference may be expected between nameplate and field test results because factory tests are conducted at full load current, normally not possible in the field. Field connections and test leads and jumpers also play a significant role in test results and it is impossible to exactly duplicate the factory test setup. Therefore the I^2R losses may be different and cause different test results. By comparing percent-reactance to nameplate impedance, the differences caused by leads and connections can be eliminated. Because reactance is only the inductive component of the impedance, I^2R losses are omitted in the test results.

Results are analyzed and applied to Table 7 to arrive at a Transformer Condition Index score adjustment.

Table 7 – Short Circuit Impedance Test Scoring	
Test Results	Adjustment to Transformer Condition Index
Less than 1 percent difference from nameplate impedance.	No Change
1 to 3 percent difference from nameplate impedance (minor degradation).	Subtract 0.5

3 to 5 percent difference from nameplate impedance (significant degradation).	Subtract 1.0
Greater than 5 percent difference from nameplate impedance (severe degradation).	Subtract 5.0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)

Test T2.3 Core-to-Ground Resistance (Megger) Test

The transformer core is intentionally grounded through one connection. The core-to-ground resistance test can detect if this connection is loose. It can also detect whether there are other undesired and inadvertent, grounds. If the intentional core ground is intact, the resultant resistance should be very low. To check for unintentional core grounds, remove the intentional ground and megger between the core and the grounded transformer tank. This test should produce very high resistance, indicating that an unintentional ground is not present. This test is to supplement dissolved gas analysis that shows generation of hot metal gases (methane, ethane, ethylene) and to indicate if a spurious, unintentional core ground is the problem. Experience can help locate the source of the problem.

Results are analyzed and applied to Table 8 to arrive at a Transformer Condition Index adjustment.

Table 8 – Core-to-Ground Resistance Test Scoring	
Test Results*	Adjustment to Transformer Condition Index
Greater than 1,000 megohms (results normal).	No Change
600 to 900 megohms.	Subtract 0.5
200 to 500 megohms.	Subtract 1.0
Less than 200 megohms.	Subtract 5.0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)

* With intentional ground disconnected.

Test T2.4 Winding Direct-Current Resistance Measurement

Careful measurement of winding resistance can detect broken conductor strands, loose connections, and bad contacts in the tap changer (DETC or LTC). Results from these measurements may indicate the need for an internal inspection. This information supplements dissolved gas analysis (DGA) and is useful when DGA shows generation of heat gases (ethane, ethylene, methane). These tests are typically performed with a micro-ohmmeter and or Wheatstone bridge. Test results are

compared between phases or with factory tests. When comparing to factory tests, a temperature correction must be employed (IEEE P62). This test should be performed only after the rest of the routine electrical tests because it may magnetize the core, affecting results of the other tests.

Results are analyzed and applied to Table 9 to arrive at a Transformer Condition Index adjustment.

Table 9 – Winding Direct-Current Resistance Measurement Scoring	
Measurement Results	Adjustment to Transformer Condition Index
No more than 5 percent difference between phases or from factory tests.	No Change
5 to 7 percent difference between phases or from factory tests.	Subtract 0.5
7 to 10 percent difference between phases or from factory tests.	Subtract 1.0
More than 10 percent between phases or from factory tests.	Subtract 5.0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)

Test T2.5 Ultrasonic and Sonic Fault Detection Measurements

These assessment tests (sometimes called Acoustic Testing) are helpful in locating internal faults. Partial discharges (corona) and low energy arcing / sparking emit energy in the range of 50 megahertz (ultrasonic), well above audible sound. To make these measurements, sensors are placed on the outside of a transformer tank to detect these ultrasonic emissions which are then converted electronically to oscilloscope traces or audible frequencies and recorded. By triangulation, a general location of a fault (corona or arcing/sparking) may be determined so that an internal inspection can be focused in that location. These devices also can detect loose shields that build up static and discharge it to the grounded tank; poor connections on bushings; bad contacts on a tap changer that are arcing / sparking; core ground problems that cause sparking / arcing; and areas of weak insulation that generate corona. Sonic testing can detect increased core and coil noise (looseness) and vibration, failing bearings in oil pumps and fans and nitrogen leaks in nitrogen blanketed transformers.

Information gained from these measurements supplements dissolved gas analysis, and provides additional support information for de-energized tests such as core ground and winding resistance tests. In addition, these tests help pinpoint areas to look for problems during internal inspections. Performing baseline tests may provide comparisons for later tests. Experience can help locate the source of the problem.

Results are analyzed and applied to Table 10 to arrive at a Transformer Condition Index adjustment.

Table 10 – Ultrasonic and Sonic Measurement Scoring	
Measurement Results	Adjustment to Transformer Condition Index
Results normal.	No Change
Low level fault indication.	Subtract 0.5
Moderate level fault indication.	Subtract 1.0
Severe fault level indication.	Subtract 2.0

Test T2.6 Vibration Analysis

Vibration can result from loose transformer core and coil segments, shield problems, loose parts, or bad bearings on oil cooling pumps or fans. Vibration analyzers are used to detect and measure the vibration. Information gained from these tests supplements ultrasonic and sonic (acoustic) fault detection tests and dissolved gas analysis. Information from these tests may indicate maintenance is needed on pumps/fans mounted external to the tank. It may also show when an internal transformer inspection is necessary. If wedging has been displaced due to paper deterioration or through-faults, vibration will increase markedly. This will also show if core and coil vibration has increased compared to baseline information. Experience can help locate the source of the problem.

Results are analyzed and applied to Table 11 to arrive at a Transformer Condition Index adjustment.

Table 11 – Vibration Analysis Scoring	
Analysis Results	Adjustment to Transformer Condition Index
Results normal.	No Change
Low vibration.	Subtract 0.5
Moderate vibration.	Subtract 1.0
Severe vibration.	Subtract 2.0

Test T2.7 Frequency Response Analysis

Frequency Response Analysis (FRA) or Sweep Frequency Response Analysis (SFRA) can determine if windings of a transformer have moved or shifted. It can be done as a factory test prior to shipment and repeated after the transformer is received on site to determine if windings have been damaged or shifted during shipping. This test is also helpful if a protective relay has tripped or a through fault, short circuit, or ground fault has occurred

A sweep frequency is generally placed on each of the high voltage windings and the signal is detected on the low-voltage windings. This provides a picture of the frequency transfer function of the windings. If the windings have been displaced or shifted, test results will differ markedly from prior tests. Test results are kept in transformer history files so they can be compared to later tests. Results are determined by comparison to baseline or previous measurements or comparison to units of similar design and construction.

Results are analyzed and applied to Table 12 to arrive at a Transformer Condition Index adjustment.

Table 12 – Frequency Response Analysis Scoring	
Test Results	Adjustment to Transformer Condition Index
No deviation compared to prior tests.	No Change
Minor deviation compared to prior tests.	Subtract 2.0
Moderate deviation compared to prior tests.	Subtract 3.0
Significant deviation compared to prior tests.	Subtract 4.0
Severe deviation compared to prior tests.	Subtract 5.0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)

Test T2.8 Internal Inspection

In some cases, it is necessary to open, partially or fully drain the oil, and perform an internal inspection to determine transformer condition. These inspections must be performed by experienced staff with proper training. Sludging, loose wedges, loose coils, poor electrical connections on bushing bottoms, burned contacts on tap changers, localized overheating signified by carbon buildup, displaced wedging or insulation, and debris and other foreign material are general areas of concern. Photographs and mapping problem locations are good means of documenting findings.

Note: Before entering and while inside the transformer, OSHA, state, local, and utility safety practices must be followed (e.g., “permitted confined space” entry practices).

Results are analyzed and applied to Table 13 to arrive at a Transformer Condition Index adjustment.

Table 13 – Internal Inspection Scoring	
Inspection Results	Adjustment to Transformer Condition Index
Conditions normal.	No Change
Minimal degradation.	Subtract 0.5
Moderate degradation.	Subtract 1.5
Severe degradation.	Subtract 5.0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)

Test T2.9 Degree of Polymerization

Winding insulation (cellulose) deterioration can be quantified by analysis of the degree of polymerization (DP) of the insulating material. This test gives an indication of the remaining structural strength of the paper insulation and is an excellent indication of the remaining life of the paper and the transformer itself. This requires analyzing a sample of the paper insulation in a laboratory to determine the deterioration of the molecular bonds of the paper.

Results are analyzed and applied to Table 14 to arrive at a Transformer Condition Index score adjustment.

Table 14 – Degree of Polymerization Test Scoring	
Test Results	Adjustment to Transformer Condition Index
900 or higher and no polymerization decrease. (Results normal.)	No Change
800-700. (Minimal polymerization decrease.)	Subtract 0.5
600-300. (Moderate polymerization decrease.)	Subtract 1.5
200. (Severe polymerization decrease. Insulation has no mechanical strength; has reached end of life.)	Subtract 5.0 (May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.)

Test T2.10 Other Specialized Diagnostic Tests

Additional tests may be applied to evaluate specific transformer problems. Some of these diagnostic tests may be considered to be of an investigative research nature. When conclusive results from other diagnostic tests are available, they may be used to make an appropriate adjustment to the Transformer Condition Index.

xx.13 **TIER 2 - TRANSFORMER CONDITION INDEX CALCULATIONS**

Enter the Tier 2 adjustments from the tables above into the Transformer Condition Assessment Summary Form at the end of this chapter. Subtract the sum of these adjustments from the Tier 1 Transformer Condition Index to arrive at the total Transformer Condition Index. An adjustment to the Data Quality Indicator score may be appropriate if additional information or test results were obtained during the Tier 2 assessment.

xx.14 **TIER 2 - TRANSFORMER CONDITION-BASED ALTERNATIVES**

The Transformer Condition Index – either modified by Tier 2 tests or not – may be sufficient for decision-making regarding transformer alternatives. The Index is also suitable for use in the risk-and-economic analysis model described elsewhere in this Guide. To determine the risk of any course of action or the long-term economic impacts, the computer model must be used. Where it is desired to consider alternatives based solely on transformer conditions, the Turbine Condition Index may be directly applied to the Turbine Condition-Based Alternatives table on the Summary Form.

Table 15 - Transformer Condition-Based Alternatives	
Transformer Condition Index	Suggested Course of Action
≥ 7.0 and ≤ 10 (Good)	Continue O&M without restriction. Repeat condition assessment as needed.
≥ 3.0 and < 7 (Fair)	Continue operation but reevaluate O&M practices. Consider using appropriate Tier 2 tests. Repeat condition assessment process as needed.
≥ 0 and < 3.0 (Poor)	Immediate evaluation including additional Tier 2 testing. Consultation with experts. Adjust O&M as prudent. Begin replacement/rehabilitation process.

Figure 1.
**Transformer Condition
 Assessment
 Methodology**

transcond 8/6/02

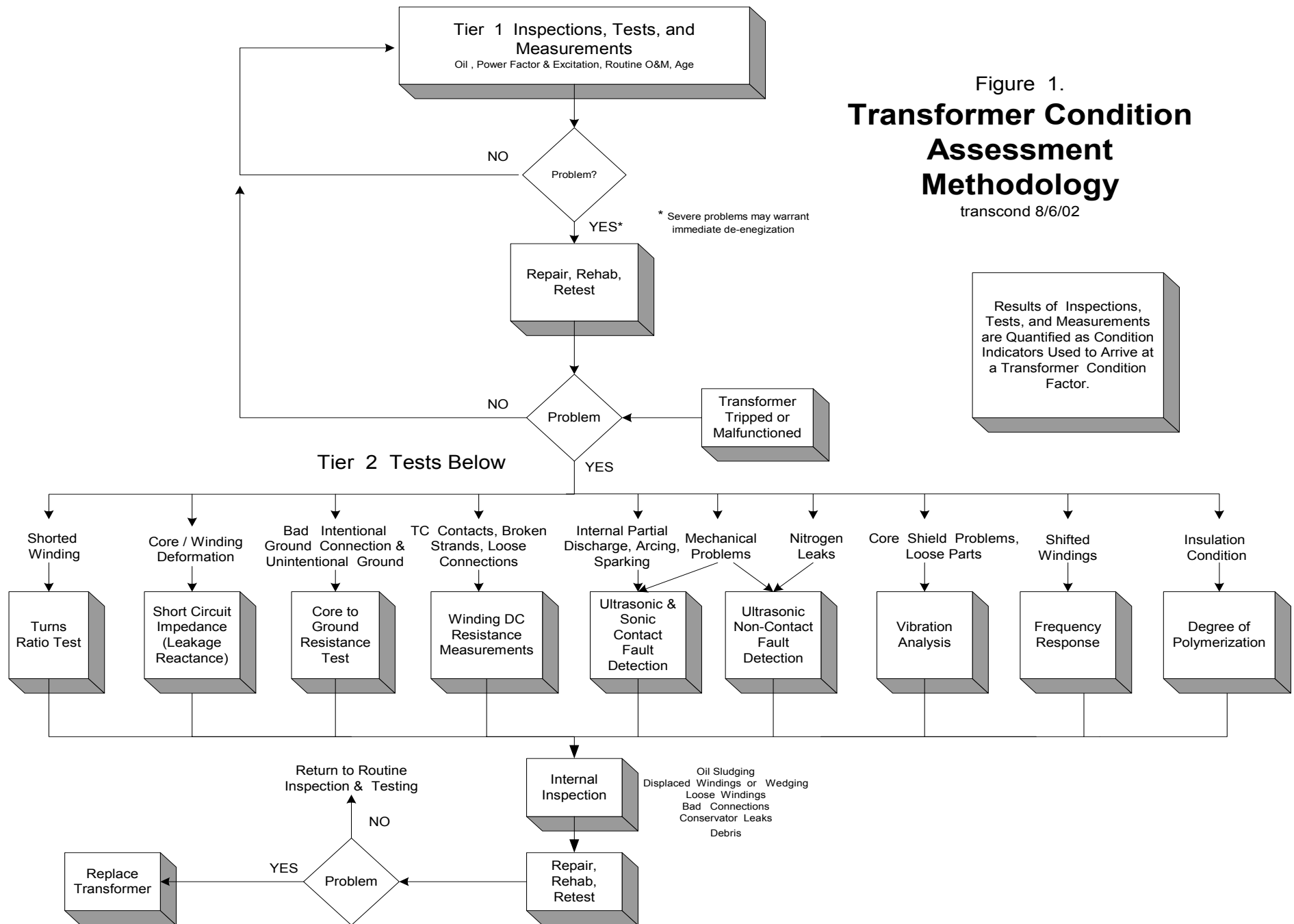


Table 16 – TRANSFORMER CONDITION ASSESSMENT

TEST	DETECTS	TOOL
ON-LINE TESTS		
Dissolved Gas Analysis	Internal arcing; bad electrical contacts; hot spots; partial discharge; and overheating of conductors, oil, tank, and cellulose insulation.	Requires laboratory analysis
Oil Physical and Chemical Tests	Moisture, degraded interfacial tension (IFT), acidity, furans, dielectric strength, and power factor.	Requires laboratory analysis
External Physical Inspection	Oil leaks, broken parts, worn paint, defective support structure, stuck indicators, noisy operation, loose connections, cooling problems with fans, pumps, etc.	Experienced staff and binoculars.
External Temperatures (Main tank and load tap changer)	Temperature monitoring with changes in load and ambient temperature.	Portable temperature data loggers and software.
Infrared Scan	Hot Spots indicating localized heating, circulating currents, blocked cooling, tap changer problems, and loose connections.	Thermographic camera and analysis software
Ultrasonic (Acoustic) Contact Fault Detection	Internal partial discharge, arcing, sparking, loose shields, poor bushing connections, bad tap changer contacts, core ground problems, and weak insulation that is causing corona.	Ultrasonic detectors and analysis software
Sonic Fault Detection	Nitrogen leaks, vacuum leaks, core and coil vibration, corona at bushings, and mechanical & bearing problems in pumps and cooling fans.	Ultrasonic probe and meter.
Vibration Analysis	Internal core, coil, and shield problems; loose parts and bad bearings.	Vibration data logger
OFF-LINE TESTS		
Doble Tests (bushing capacitance, insulation power factor, tip up, excitation current)	Loss of winding insulation integrity, loss of bushing insulation integrity, and winding moisture.	Doble Test Equipment
Turns Ratio	Shorted windings	Doble test equipment or turns ratio tester
Short Circuit Impedance	Deformation of the core or winding	Doble or equivalent test equipment

Table 16 – TRANSFORMER CONDITION ASSESSMENT

TEST	DETECTS	TOOL
Core to Ground Resistance (External test may be possible depending on transformer construction)	Bad connection on intentional core ground; and existence of unintentional grounds.	Megger
Winding DC Resistance Measurements	Broken strands, loose connections, bad tap changer contacts.	Wheatstone Bridge (1 ohm and greater) Kelvin Bridge micro-ohmmeter (Less than 1 ohm)
Frequency Response Analysis	Shifted windings.	Doble or equivalent sweep frequency analyzer
Internal Inspection	Oil sludging, displaced winding or wedging, loose windings, bad connections, localized heating, debris and foreign objects.	Experienced staff, micro-ohm meter.
Degree of Polymerization	Insulation condition (life expectancy)	Laboratory analysis of paper sample.

TRANSFORMER TIER 1 CONDITION ASSESSMENT SUMMARY

Date: _____ Transformer Identifier: _____
 Location: _____ Manufacturer: _____ Yr. Mfd. _____
 No. of Phases: _____ MVA: _____ Voltage: _____

Tier 1 Transformer Condition Summary (For instructions on indicator scoring, please refer to condition assessment guide)				
No.	Condition Indicator	Score	× Weighting Factor	= Total Score
1	Oil Analysis (Score must be 0, 1, 2, or 3)		1.143	
2	Power Factor and Excitation Current Tests (Score must be 0, 1, 2, or 3)		0.952	
3	Operation and Maintenance History (Score must be 0, 1, 2, or 3)		0.762	
4	Age (Score must be 1, 2, or 3)		0.476	
	Tier 1 Transformer Condition Index (Sum of individual Total Scores) (Condition Index should be between 0 and 10)			

Data Quality Indicator (Value must be 0, 4, 7, or 10)	
---	--

Evaluator: _____ Technical Review: _____
 Management Review: _____ Copies to: _____

Transformer Condition-Based Alternatives	
Transformer Condition Index	Suggested Course of Action
≥ 7.0 and ≤ 10 (Good)	Continue O&M without restriction. Repeat condition assessment as needed.
≥ 3.0 and < 7 (Fair)	Continue operation but reevaluate O&M practices. Consider using appropriate Tier 2 tests. Repeat condition assessment process as needed.
≥ 0 and < 3.0 (Poor)	Immediate evaluation including additional Tier 2 testing. Consultation with experts. Adjust O&M as prudent. Begin replacement/rehabilitation process.

Note: A Transformer Condition Index of zero strongly indicates that the transformer should not be re-energized until repair raises the condition index or the transformer is replaced.

TRANSFORMER TIER 2 CONDITION ASSESSMENT SUMMARY

Tier 2 Transformer Condition Summary	
Tier 2 Test	Adjustment to Tier 1 Condition Index
T2.1 Turns Ratio Test	
T2.2 Short Circuit Impedance Test	
T2.3 Core-to-Ground Resistance (Megger) Test	
T2.4 Winding DC Resistance Measurement	
T2.5 Ultrasonic and Sonic Fault Detection Measurements	
T2.6 Vibration Analysis	
T2.7 Frequency Response Analysis	
T2.8 Internal Inspection	
T2.9 Degree of Polymerization	
T2.10 Other Specialized Diagnostic Tests	
Tier 2 Adjustments to Transformer Condition Index (Sum of individual adjustments)	

Data Quality Indicator (Value must be 0, 4, 7, or 10)	
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To calculate the net Transformer Condition Index, subtract the Tier 2 Adjustments from the Tier 1 Condition Index. (Condition Index should be between 0 and 10):

Tier 1 Transformer Condition Index _____

minus **Tier 2 Adjustments** _____

Transformer Condition Index _____

Data Quality Indicator _____

Evaluator(s): _____ Date: _____

Technical Reviewer: _____ Management Review: _____

Copies to: _____

(Attach supporting documentation.)